ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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1407 W. North Temple, Suite 330
Salt Lake City, Utah 84116

November 17, 2015

VIA HAND DELIVERY

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Re: CASE NO. PAC-E-15-12
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CAPACITY DEFICIENCY PERIOD TO BE USED FOR AVOIDED COST CALCULATIONS

Dear Ms. Jewell:

Please find enclosed for filing an original and seven (7) copies of Rocky Mountain Power's reply comments in the above-referenced matter.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Jeffrey K. Larsen/cm

Jeffrey K. Larsen
Vice President, Regulation

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Attorney for Rocky Mountain Power

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S APPLICATION TO APPROVE CAPACITY DEFICIENCY FOR AVOIDED COST CALCULATIONS	**CASE NO. PAC-E-15-12** **REPLY COMMENTS OF ROCKY MOUNTAIN POWER**

PacifiCorp, d.b.a. Rocky Mountain Power ("Rocky Mountain Power" or "Company"), hereby provides reply comments in response to comments filed by the Staff of the Idaho Public Utilities Commission ("Staff"). Staff recommends the Commission reject the Company's request to adopt summer 2025 as the Company's first capacity deficit for use in the surrogate avoided resource ("SAR") model. Instead, Staff recommends the Commission adopt summer 2015 as the first capacity deficit, reflecting the Company's updated system position but excluding available front office transactions ("FOTs").

BACKGROUND

On October 13, 2015, the Company filed an application requesting the Commission approve summer 2025 as the updated capacity deficiency period for use in the SAR avoided cost calculations. The Company's application was consistent with the Commission's Order No. 32697 stating that payments to qualifying facilities ("QFs") should recognize the utility's capacity needs:

"In calculating a QF's ability to contribute to a utility's need for capacity, we find it

> reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of true avoided cost for the QF power."[1]

Consistent with the 2015 Integrated Resource Plan ("IRP"), the Company included FOTs in calculating the SAR deficiency period accurately reflecting the fact that the Company's long term resource plan does not include any new generation capacity until 2028.

REPLY COMMENTS

Staff's recommendation to exclude available FOTs in determining the deficiency period is based primarily on its assessment that FOTs do not represent committed market purchases and that the must purchase obligation mandated by PURPA "does not permit utilities to reject offers to sell by QFs in lieu of utility purchases from the market."[2] Staff clarifies its position to be that "utilities should not be allowed to rely on uncommitted, non-specific market purchases as an excuse for not needing capacity from QFs."[3]

Contrary to Staff's assertion, inclusion of FOTs in determining the SAR deficiency period does not serve as a rejection of QF purchases, but as a means to recognize in standard avoided costs the timing and costs of the different resources used to balance the Company's capacity needs and achieve the ratepayer indifference standard mandated by PURPA. Staff cited Order No. 32697 which reiterates that the avoided cost rate shall not exceed the "'incremental cost' to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source." Under the approved SAR

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[1] *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies for Calculating Avoided Cost Rates,* Case No. GNR-E-11-03, Order No. 32697, p.21 (December 18, 2012).

[2] *In the Matter of PacifiCorp DBA Rocky Mountain Power's Application to Approve Capacity Deficiency for Avoided Cost Calculations,* Case No. PAC-E-15-12, Comments of the Commission Staff, p. 5 (November 10, 2015).

[3] *Id.*

method, once a utility becomes capacity deficient avoided costs include both the variable and fixed costs of a generic proxy combined cycle combustion turbine ("CCCT"). Staff's recommendation to adopt summer 2015 as the first capacity deficit fails to recognize the Company's ability to utilize its existing firm transmission capacity to procure resources in the wholesale market rather than acquire a new generating resource at a higher cost. Staff's recommendation will result in retail customers paying a QF the full cost of a CCCT immediately even though the Company's 2015 IRP does not include a new CCCT resource until 2028.

In Order No. 32697 the Commission stated that "A utility cannot be compensated by its customers for energy produced from a generating facility until the utility establishes the need for such new generation."[4] As demonstrated in the 2015 IRP, the Company does not need additional generation resources until 2028, but if FOTs are excluded from the determination of the SAR deficiency period customers will be required to pay QF prices based on an unneeded generic CCCT beginning in 2015. Excluding FOTs from the determination of the SAR deficiency period clearly does not result in "a rate that holds utility customers harmless."[5]

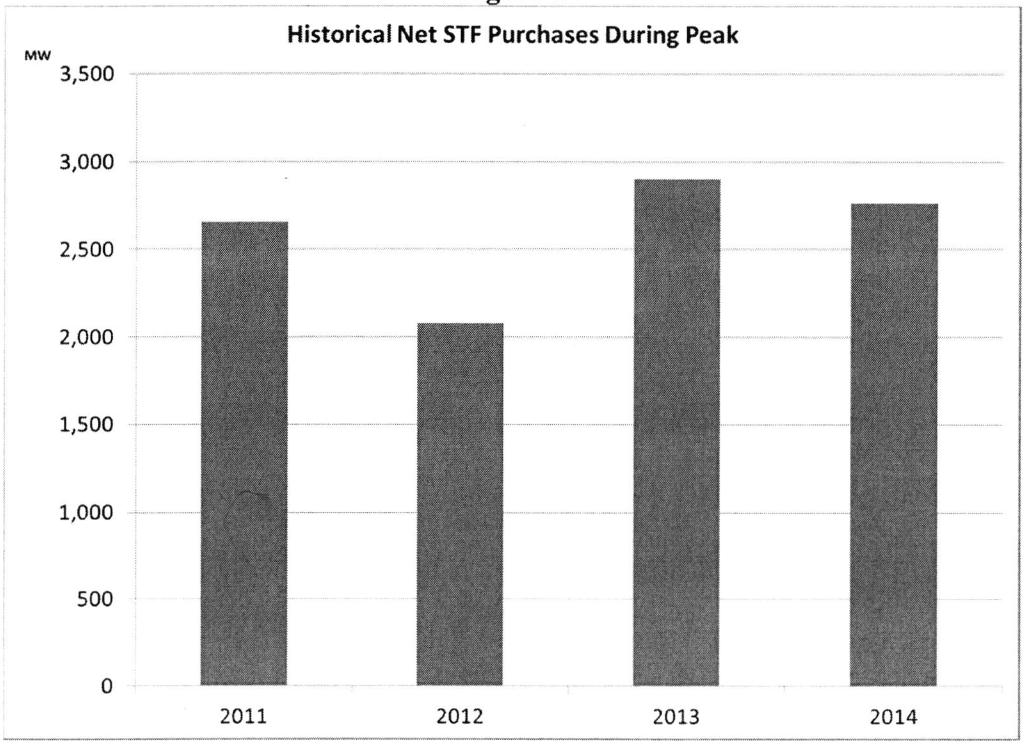
Staff's exclusion of FOTs is based solely on the fact that these FOTs are "uncommitted," and Staff believes that "uncommitted resources... should not be counted in determining a utility's capacity deficit position[.]"[6] As described in the Company's 2015 IRP, FOTs are "proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the Company cover short positions."[7] The Company's FOT selections are as committed and specific as its 2028 CCCT, which the Commission has found appropriate for determining the avoided costs for large QFs. While Staff indicates "utilities should not be

[4] Order No. 32697, p15.
[5] Order No. 32697, p16.
[6] *Supra., fn. 1*
[7] PacifiCorp 2015 IRP, p128.

allowed to rely on uncommitted, non-specific market purchases" their alternative is to use the costs of an uncommitted, non-specific CCCT.

Furthermore, the 1,670 MW of 'Available Front Office Transactions' included in Table 1 of the Company's application (Table 1 shows the 2015 IRP system capacity loads and resources) represent firm transmission rights currently owned by the Company and included in customers' rates, which enable access to diverse wholesale market resources. In actual operations and in the 2015 IRP this transmission capacity is routinely relied on to facilitate procurement of available FOTs to balance the Company's capacity needs and minimize costs. For example, Figure 1 below illustrates the amount of short-term firm ("STF") wholesale market purchases, net of offsetting wholesale market sales, made by the Company at the time of its system peak load from 2011 through 2014.

Figure 1



As demonstrated by actual transactions, and as projected in the 2015 IRP, the Company will rely on FOTs to balance its capacity needs before the next major thermal resource acquisition in 2028. The IRP is the Company's long term plan for serving customers and it relies on FOTs because they provide the best balance of cost and risk. Recognizing 1,670 MW of firm transmission access to wholesale markets in the determination of the SAR deficiency period more closely aligns the capacity deficit period with the Company's IRP and the costs that can be avoided by the addition of a QF.

Figure 2 compares the SAR avoided costs to current forward wholesale market prices for electricity at the Mid-Columbia and Palo Verde markets. SAR costs are shown separately for variable costs only (the avoided cost rates paid prior to the SAR capacity deficit period) and variable plus fixed costs (the SAR avoided cost rates paid if the utility is deemed to be capacity deficit).

Figure 2
SAR Avoided Costs Versus Forward Market Prices

	Current SAR Avoided Costs Base Load Resources ($/MWh)		September 2015 Official Forward Price Curve ($/MWh)	
Year	Variable Costs	Variable + Fixed Costs	Mid Columbia	Palo Verde
2016	$34.06	$53.95	$23.11	$25.81
2017	$34.42	$54.61	$24.80	$26.65
2018	$35.69	$56.17	$26.28	$27.50
2019	$39.37	$60.15	$27.59	$28.91
2020	$43.05	$64.13	$30.05	$30.82
2021	$46.00	$67.39	$31.61	$33.42
2022	$48.19	$69.89	$33.13	$37.09
2023	$49.99	$72.01	$34.91	$40.33
2024	$51.27	$73.62	$36.89	$42.29
2025	$53.87	$76.55	$39.12	$44.48

As demonstrated in Figure 2, avoided costs, inclusive of the fixed costs for a proxy CCCT, are significantly higher than current prices for wholesale market transactions. If the Company is not allowed to recognize existing firm transmission access to firm market purchases when determining the SAR deficit period, retail customers end up paying more than avoided costs – customers avoid firm market purchases but incur the fixed and variable costs of a CCCT that will not be avoided by the Company. Compared to the average market prices shown in Figure 2, payments to a base load QF generating 10 average megawatts would be more than $2.5 million higher on an annual basis prior to the first capacity deficit year.

The Company recently demonstrated in Case No. PAC-E-15-03, that its current risk management policy generally precludes the Company from entering into long term transactions with terms longer than three years. This policy allows the Company the necessary flexibility to serve load while managing the risk of changing wholesale market prices. In contrast, if the FOTs were already contractually committed, customers could be potentially harmed by the addition of a new QF as the utility would be obligated to take energy from the contracted FOT and the QF. In other words, FOTs cannot be avoided if they are contractually committed. In Order No. 33357 of Case No. PAC-E-15-03 the Commission recognized the timing of new generation capacity when determining the proper term length for contracts under the IRP Method for determining non-standard avoided costs in Idaho. The Commission stated, "As we have said in previous Orders, a utility is to begin payments to a QF for capacity 'at such time as the utility becomes capacity deficient...[w]e recognize that a new two-year contract would be unlikely to reach a capacity deficiency date."[8] The Commission also recognized that, according to the 2015 IRP, the capacity surplus period extended to "2028 for PacifiCorp."[9]

Finally, Idaho Power makes a similar assumption as PacifiCorp regarding access to wholesale market purchases in its IRP and in its determination of the first capacity deficiency for the SAR method that was just approved by the Commission.[10] In fact, Staff explicitly recognized Idaho Power's use of available transmission capacity to make future market purchases in its comments filed August 21, 2015, in Case No. IPC-E-15-20. Attachment A to Staff's comments is taken from the Peak-Hour Load and Resource Balance tables from Idaho Power's 2015 IRP and clearly shows Idaho Power's reliance on future, uncommitted, market purchases to meet its capacity needs. In its comments, Staff explained that Idaho Power's deficiency period was moving up one year (from 2025 to 2024) because of the termination of four PURPA contracts which equated to 74 MW of lost capacity. When Staff verified this change it did not conclude that Idaho Power was now deficient 74 MW because it no longer had committed resources, but instead confirmed that Idaho Power was deficient only 47 MW because it still had 27 MW transmission capacity available which could be used for market purchases to meet peak demand. In Case No. IPC-E-15-20, the Commission approved a first capacity deficit year of 2024 for Idaho Power, and the deficit year determination recognized access to wholesale markets as part of the resource balance. Inconsistent treatment for PacifiCorp in the current case will result in avoided cost rates that are approximately $20/MWh higher for PacifiCorp compared to Idaho Power each year through 2023. Such disparity encourages QF developers located in Idaho Power's service territory to obtain a transmission wheel to PacifiCorp to take

[8] Order No. 33357, p25.
[9] Order No. 33357, p24.
[10] Case No. IPC-E-15-20, Order No. 33377.

advantage of higher prices despite the fact that, like Idaho Power, the Company has no need for new resources in the next decade.

Recognizing available FOTs that are facilitated by existing firm transmission access to wholesale markets in the determination of the SAR deficiency period results in avoided costs rates that are consistent with the 2015 IRP by more closely aligning the time period in which QFs are paid the full cost of a CCCT with the time period the Company plans to acquire such additional generation capacity. Removing FOTs from the equation will result in retail customers paying a QF the full cost of a CCCT immediately even though the Company's 2015 IRP does not include a new CCCT resource until 2028, which clearly does not result in "a rate that holds utility customers harmless."[11]

RECOMMENDATION

For the reasons set forth above, Rocky Mountain Power respectfully requests that the Commission approve its application as filed, identifying summer 2025 as the first capacity deficit for use in the SAR model.

DATED this 17th day of November 2015.

Yvonne R. Hogle

Yvonne R. Hogle
Rocky Mountain Power

[11] Order No. 32697, p16.